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Probabilistic estimates of injectivity and capacity for large scale CO_2 storage in the Gippsland Basin, Victoria, Australia

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Abstract

Monte Carlo simulations of injectivity and static capacity explore the range of variation and uncertainty of key parameters (permeability, porosity, reservoir thickness, etc.) in 3 selected areas in the Gippsland Basin, Victoria, Australia. The uncertainty range in specific data is represented by a probability density function. A Tornado plot ranks the parameters of uncertainty impact on the carbon dioxide (CO_2) storage potential, which is valuable to inform the work program for appraisal to reduce uncertainty and obtain confidence on the suitability of those areas. The attained P50 (50% likelihood) injection rate into the Golden Beach Subgroup is 0.5 - 3.0 Mt/a. More than 84% of the uncertainty can be attributed to uncertainty in permeability. Injection rates for the Halibut are 1.4 and 0.9 Mt/a for Areas 2 and 3, respectively. The likelihood is high that all areas possess storage capacity in the order of tens of millions of tonnes.

Keywords: Injectivity, dynamic, Gippsland, uncertainty, industrial, Golden Beach, Latrobe, Halibut.

1. Introduction

An approach to find “Large Scale Storage Sites” (LASSIE) is used to screen and prioritize portions of the Gippsland Basin for industrial scale (sustaining for decades more than 1 million tonnes per annum, or > 1Mt/a) CO_2 geological storage. The study delineates the main uncertainties and creates a work program to reduce those uncertainties that was submitted to the Victorian Government as part of a tenement application for exploration and appraisal. The probabilistic modeling that is used to inform uncertainty and its impact on the assessment is the subject of this paper.

The aquifer storage play concept consists of the Lakes Entrance Formation (seal) and siliciclastic reservoir rocks in the Cobia, Halibut and Golden Beach Subgroups of the Latrobe Group of the Gippsland Basin (Victoria, Australia).

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Monte Carlo simulations of injectivity and static capacity are performed for three selected areas in the Gippsland Basin (Fig. 1a): Area 1 samples mostly the Golden Beach Subgroup and has greater data coverage than other areas, while Area 2 and 3 focus on the Halibut Subgroup (Fig. 1b).

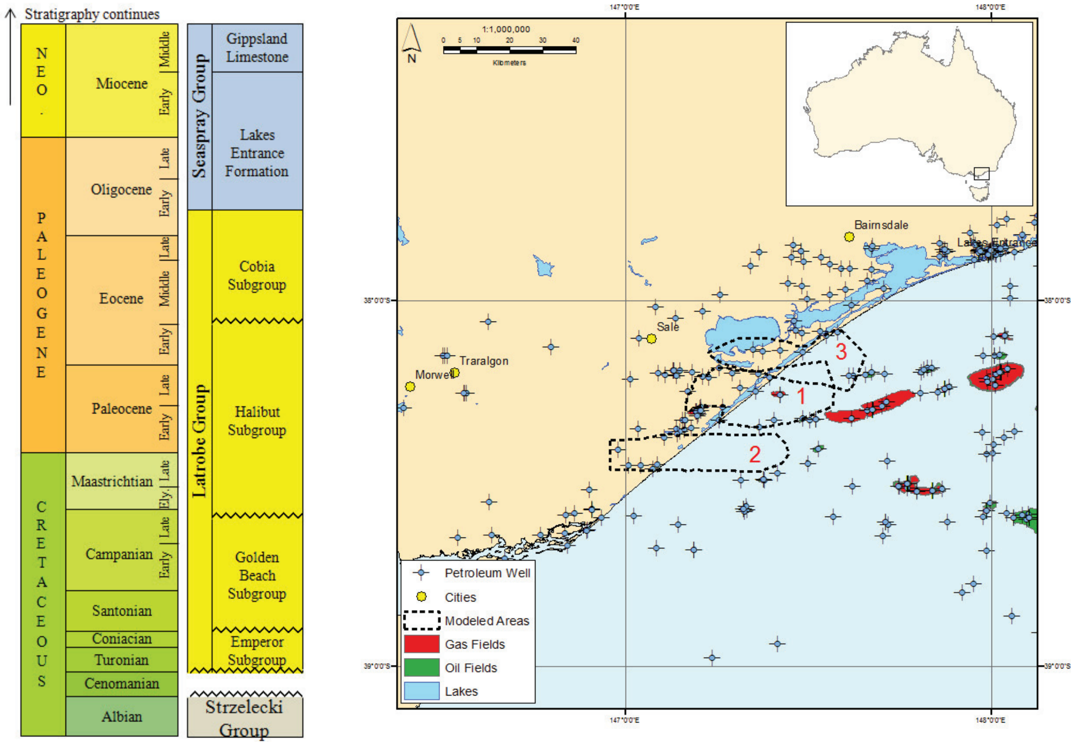

Fig. 1. (a) Stratigraphic column of the Gippsland Basin; (b) Map with areas of interest marked by red numbers.

2. Methodology for probabilistic assessment of injectivity and capacity

The methodology uses an analytical expression of injectivity and capacity as a function of parameters such as permeability, porosity and others. Each parameter is represented by a probability distribution function (PDF). A Monte Carlo simulation exercise interrogates the PDFs to yield a population of values. The likelihood of specific outcomes is obtained and the degree of impact of the uncertainty of each parameter. The parameters of most influence will need to be addressed in an exploration program to reduce uncertainty and obtain confidence on the suitability of the areas for potential CO_2 storage.

The data ranges are collated for each Area of interest (1, 2 and 3). In the lack of specific data, best practices from the oil and gas industry are applied. The results (likelihood) at P10, P50 and P90 (10%, 50% and 90% probability) are produced for each Area separately. Only the process in Area 1 is detailed.

The analytical assessment of storage *injectivity* uses the following modified form of Darcy's law approximation for pseudo-steady state compressible fluid flow in a porous medium:

$$q_{CO_2} = \frac{k_{absolute}\ k_{rCO2} h_{gross} NTG \cdot (p_{inj} - p_{res})}{25.15 \bar{\mu}_{CO2} \bar{B}_{CO2} \left[\ln\left(\frac{r_e}{r_w} \right) - 0.75 + S \right]} \qquad (1)$$

It assumes that pseudo steady-state reservoir behavior dominates the reservoir response throughout the injection period. The initial reservoir transient response is neglected as it occurs over a relatively short time span.

Effective storage capacity is derived from the estimation of pore space available for CO_2 storage. It is translated into mass using CO_2 density evaluated at reservoir conditions. The expression that defines storage capacity is:

$$m_{CO_2} = Ah_{gross} \cdot NTG \cdot \phi_{total} \frac{\phi_{effective}}{\phi_{total}} \cdot (1 - S_{wir}) \cdot \rho_{CO_2} E_{storage} \qquad (2)$$

3. Probabilistic Density Functions for Area 1

3.1. Absolute Permeability

Two injection scenarios corresponding to reservoirs with different absolute permeability values are investigated: Reference and High Permeability Cases. In addition a Combined Case is created in which the Reference Case PDF is given double the weight of the High Permeability Case. This honors the judgment that while both cases are based on existing data, the Reference Case is considered more likely. A normal PDF is fitted to the data derived from modeling of core-calibrated log-derived permeability data from two existing wells (Dutson Downs-1 and Golden Beach-1A). For High Permeability scenario, 60mD is added to the log-derived permeability data of the Reference Case in the reservoir. The PDF is truncated at minimum and maximum modeled permeability (Table 1).

3.2. Initial pore pressure gradient

A normal PDF is used for initial reservoir pore pressure gradient with the mean at the hydrostatic gradient for pure water. The standard deviation is 10% of the mean. The PDF is truncated at a minimum of 0.09 bar/m and at a maximum of 0.11 bar/m. The low side of this distribution recognizes regional depletion caused by offshore oil and gas extraction and/or onshore depletion.

3.3. Gross thickness

A lognormal PDF is fitted to the data derived from the spatial distribution of gross thickness within the area. The reservoir isopach results from seismic interpretation and formation depth data from wells. The PDF was truncated at a minimum and a maximum gross thickness observed, respectively (Table 1).

3.4. Net to gross ratio

A normal PDF is fitted to net-to-gross derived from geostatistical modeling of log data from two wells (Dutson Downs-1 and Golden Beach-1A). It was truncated at a minimum and at maximum observed values, respectively (Table 1).

3.5. Relative permeability

A uniform PDF is utilized for CO_2 relative permeability. The minimum and maximum values are based on an assumed water saturation evolution in the reservoir during initial injection period and are derived from analogous laboratory test results ranging from 0.1 to 0.175 [1].

3.6. Fracture gradient

A normal PDF is utilized for fracture gradient. The mean value is typical of an extensional setting. The standard deviation is 10% of the mean. The PDF is truncated at a minimum and maximum of 0.67 psi/ft and 0.8 psi/ft, respectively (Table 1).

3.7. Wellbore Skin

A normal PDF was assumed for wellbore skin at a mean value of 4. In contrast to other parameters, this PDF was not driven by data. The mean value is based on an assumption about the use of carefully selected drilling fluids, aimed at minimizing formation damage based on work not presented here. A small standard deviation (10% of mean value) was assumed to provide a spread of uncertainty.

3.8. Area

The area suitable for CO_2 injection spans a rough estimate of plume diameter from numerical simulations (a few kilometers) to the whole area of interest. A triangular PDF is used for suitable reservoir. Boundaries are defined by considering reservoir parameters such as depth, thickness, fault and legacy well distributions, reservoir erosion limits, as well as existing petroleum tenement boundaries. The PDF is truncated at a minimum corresponding to a numerically simulated single-well CO_2 footprint and at a maximum corresponding to the area within defined boundaries. The likeliest value is arbitrarily fixed at 20% of the maximum, the estimated fraction of the area that would ultimately be developed (Table 1).

3.9. Total porosity

A normal PDF is fitted to data derived from geostatistical modeling of log data from two existing wells (Dutson Downs-1 and Golden Beach-1A). The PDF was truncated at a minimum and maximum observed porosity, respectively (Table 1).

3.10. Effective to total porosity ratio

A normal PDF is used for effective to total porosity ratio with mean 0.9 to acknowledge possible porosity impairment. The standard deviation is 10% of the mean. The PDF was truncated at a maximum value of 1 (Table 1).

3.11. Irreducible water saturation

A normal PDF is used for irreducible water saturation. The mean value is typically observed in the oil and gas industry. The standard deviation was set at 20% of the mean. The PDF is truncated at a minimum of 10% and at a maximum of 30% (Table 1).

3.12. Final pore pressure gradient

A normal PDF is used for final reservoir pore pressure. The mean is obtained from the range of values obtained by numerical simulation. The standard deviation is 10% of the mean. The PDF is truncated at a minimum value corresponding to initial pore pressure gradient and at a maximum of 0.12 (Table 1).

3.13. Storage efficiency

A normal PDF was utilized for storage efficiency. The mean value was set according to the range of values typically utilized in CO_2 storage application in Schlumberger. The standard deviation was set at 20% of the mean value (Table 1).

Table 1. Ranges of values for property PDFs.

Parameter	Unit of measurement		Mean value	Standard deviation	Minimum value	Maximum value
Absolute permeability	mD	High	45	12	21	66
		Low	7	7	0	24
Gross thickness	m		504	190	200	1000
Net to gross thickness ratio	Dimensionless		0.52	0.18	0.14	0.90
Fracture gradient	psi/ft		0.73	0.07	0.67	0.80
Area	10^6 m^2		1.5	101	20	Area
Total porosity	Dimensionless		0.13	0.02	0.09	0.18
Effective to total porosity ratio	Dimensionless		0.9	0.09	0	1.0
Irreducible water saturation	%		20%	4%	10%	30%
Final pore pressure gradient	bar/m		0.11	0.011	0.1	0.12
Storage efficiency	%		2.5	5	-	-

4. Probabilistic modeling results

The results of Monte Carlo simulation indicate mean, mode, and median single-well CO_2 *injection rate* values of 1890 t/d, 490 t/d, and 1390 t/day (0.69 Mt/a, 0.18 Mt/a and 0.5 Mt/a), respectively (Fig. 2a). There is 90% chance of storage injection rate being more than 330 t/d (0.12 Mt/a) and 10% chance of it being more than 4100 t/d (1.5 Mt/a). Furthermore, the most sensitive parameters to the outcome are absolute permeability, gross thickness, and net-to-gross thickness ratio (Fig. 2b). To reduce uncertainty of these parameters core measurements, well logs and well testing is necessary for permeability and seismic surveys combined with well logs would improve gross thickness and net-to-gross knowledge.

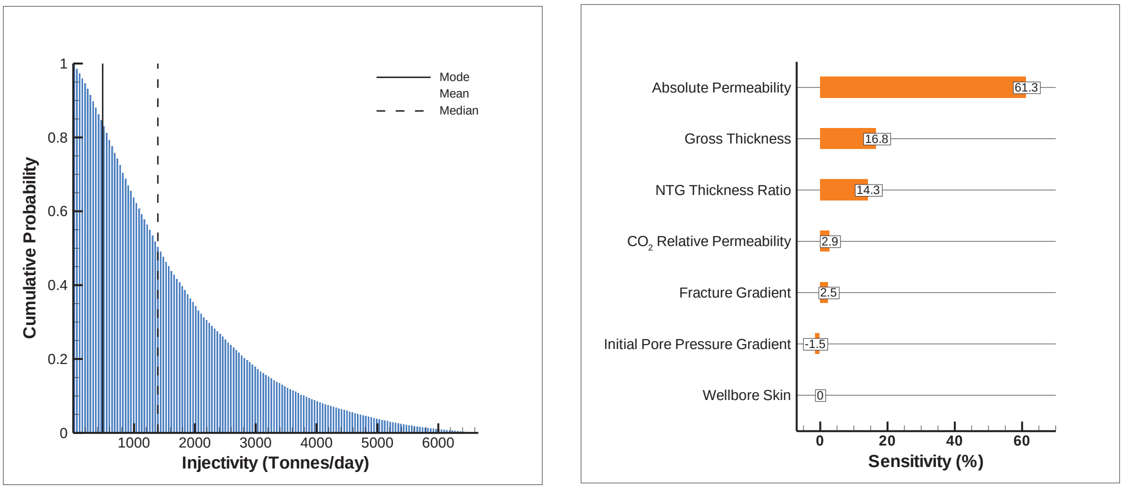

Fig. 2. Reference Case, Area1: (a) Cumulative probability plots for injection rate assessment. From left to right are indicated in t/day: mode (490), median (1390) and mean (1890); (b) Sensitivity plot of impact of uncertainties in individual parameters: uncertainties in absolute permeability (61%), gross thickness (17%) and net-to-gross (14%) influence the most the spread of injectivity.

The Monte Carlo simulations for *effective capacity* of the Golden Beach Subgroup indicate mean, mode, and median CO_2 *capacity* is 164 Mt, 57 Mt, and 125 Mt, respectively (Fig. 3a). There is 90% chance of storage capacity being more than 38 Mt and a 10% chance of it exceeding 340 Mt. The Tornado plot in Fig. 3b shows that the most sensitive parameters to the outcome are area, gross thickness, and net-to-gross thickness ratio. The last two represent the net reservoir thickness available for storage. Area estimates reflect large uncertainty in plume development and knowledge on heterogeneities (lateral as well as vertical, the last reflected in the net-to-gross range).

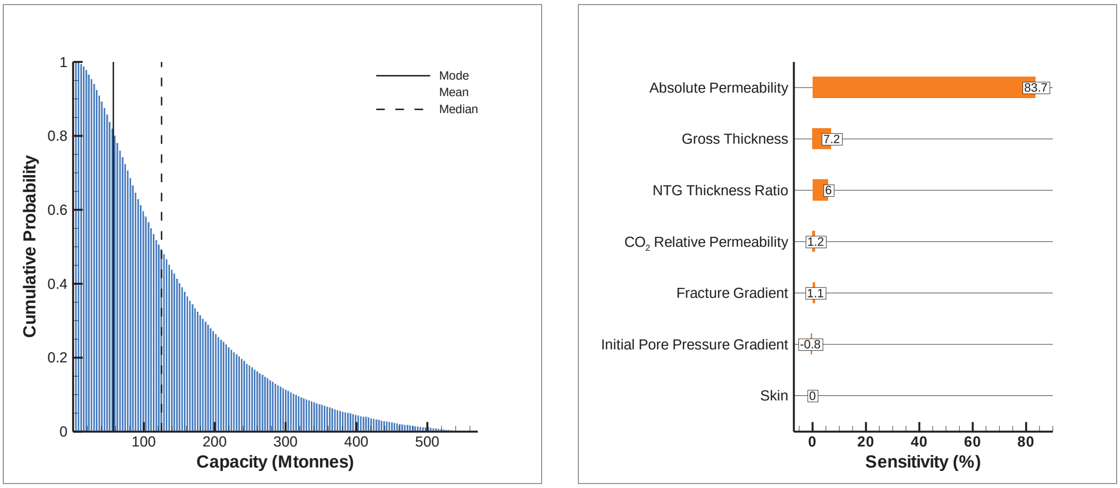

Fig. 3. Reference Case, Area 1: (a) Cumulative Probability plots for capacity assessment; (b) Sensitivity plot of impact of uncertainties in individual parameters: uncertainties in suitable area (54%), gross thickness (21%) and net-to-gross (16%) influence the most the spread in capacity.

5. Summary of probabilistic assessment results for all areas and conclusions

The analytical assessment of *injectivity* yields for Area 2 and Area 3 are performed according to the same workflow as for Area 1. Rates of the order of at least hundreds of t/d are indicated by the P90 values in Table 11. The injection pressure limit in Area 2 and Area 3 are suppressed to about 70% of the fracture gradient, while in Area 1, it is 90%. So given the uncertainties in all the data that were scrutinized, it seems likely that some combination of injection horizons will be able to sustain an industrial scale project. Better estimates are only possible with the results of the appraisal phase.

Table. 2. Injection rates and confidence levels for Areas 1, 2 and 3 (single vertical well into a single formation is assumed).

Area	Play	Mean	Mode	P50	P10	P90
		(Injection Rate in Mt/a)				
1	Golden Beach (Hi-k)	3.48	2.11	2.98	6.30	1.29
1	Golden Beach (Ref-k)	0.69	0.18	0.51	1.50	0.12
1	GB (Combined w/ 2x Ref-k Weight)	1.01	0.07	0.49	2.63	0.07
2	Halibut	1.88	0.69	1.39	3.80	0.47
3	Halibut	1.06	0.60	0.89	2.01	0.3

The analytical assessment of static effective *capacity* yields high likelihood of Area 1, Area 2 and Area 3 possessing CO_2 storage capacity in the order of tens of Mt, suggested by P90 values in Table 12. It is important to recognize that this theoretical capacity does not indicate (i) how many wells are required to access this pore volume and (ii) at what rate the volume can be filled with CO_2. The results allow confidence that even with large uncertainty, capacity is appropriate for industrial scale injection projects.

Table. 3. Summary of Storage Capacity Assessment Results for Area 1, Area 2, and Area 3.

Area	Play	Mean	Mode	Median	P10	P90
		(Storage Capacity in Mt)				
1	Golden Beach	164	57	125	340	38
2	Halibut	66	33	54	131	19
3	Halibut	98	44	78	193	29

While there are many uncertainties, due to lack of quality and proximal well data, it appears reasonable to expect that industrial scale injection (>1Mt/a and storage capacity of 40-200 Mt) could be performed in the basin, and this warrants transition to the appraisal stage (i.e. grant-supported investment in data acquisition). The appraisal stage should focus on acquiring data of the most governing parameters, such as absolute permeability, gross thickness, NTG, relative permeability, and fracture gradient. This would allow a more detailed evaluation of the storage site performance.

References

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Appendix A. Nomenclature

q_{CO_2}	CO_2 injection rate (10^3 scf/d)
$k_{absolute}$	Absolute reservoir permeability (mD)
k_{rCO_2}	CO_2 relative permeability (dimensionless)
h_{gross}	Gross thickness (m)
NTG	Net to gross thickness ratio (dimensionless)
p_{inj}	Bottomhole injection pressure (psi)
p_{res}	Reservoir pore pressure (psi)
$\overline{\mu}_{CO_2}$	Average CO_2 viscosity (cP)
$\overline{B}_{CO_2}$	Average CO_2 formation volume factor ($ft^3/10^3$scf)
r_e	Reservoir drainage radius (ft)
r_w	Wellbore radius (ft)
S	Well skin (dimensionless)
m_{CO_2}	CO_2 mass (kg)
h_{gross}	Gross thickness (m)
NTG	Net to gross thickness ratio (dimensionless)
ρ_{CO_2}	In-situ CO_2 density